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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS
KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY UTILITIES, INC. FOR A RATE INCREASE.	DOCKET NO. G-02527A-09-0088
IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY UTILITIES, INC. GAS DIVISION FOR APPROVAL OF A LOAN.	DOCKET NO. G-02527A-09-0032
IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY UTILITIES, INC. WATER DIVISION FOR A RATE INCREASE.	DOCKET NO. W-02527A-09-0201
IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY UTILITIES, INC. WATER DIVISION FOR APPROVAL OF A LOAN.	DOCKET NO. W-02527A-09-0033
IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY ELECTRIC COOPERATIVE, INC. FOR APPROVAL OF A LOAN GUARANTEE.	DOCKET NO. E-01749A-09-0087 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

The Utilities Division of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony related to rate design and cost of service of Staff Witnesses Robert G. Gray and Prem K. Bahl in the above-referenced matter.

RESPECTFULLY SUBMITTED this day 23rd day of December, 2009.

Arizona Corporation Commission
DOCKETED
DEC 23 2009
DOCKETED BY

Robin R. Mitchell, Staff Attorney
Kevin O. Torrey, Staff Attorney
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

. . .

. . .

Original and thirteen (13) copies of the foregoing were filed this 23rd day of December, 2009 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing were mailed this 23rd day of December, 2009 to:

John V. Wallace
Grand Canyon State Electric
Cooperative Association
120 North 44th Street, Suite 100
Phoenix, Arizona 85034

Russ Barney
Graham County Electric Cooperative, Inc.
P.O. Box Drawer B
Pima, Arizona 85543

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY UTILITIES, INC. FOR JUST AND REASONABLE RATES AND CHARGES.	)))))	DOCKET NO. G-02527A-09-0088

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

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SCHEDULES

EXECUTIVE SUMMARY
GRAHAM COUNTY UTILITIES, INC.
DOCKET NO. G-02527A-09-0088

My testimony in this proceeding addresses the issue of rate design for Graham County Utilities Inc. ("Graham"). My testimony also includes a review of Graham's natural gas procurement activities.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am an Executive Consultant III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant III.

A. In my capacity as an Executive Consultant III, I conduct analysis and provide recommendations to the Commission on a variety of electricity, natural gas, and water/wastewater matters. A copy of my resume is attached as Exhibit RGG-1.

Q. What is the scope of this testimony?

A. This testimony presents Staff's positions regarding rate design for Graham as well as Staff's review of Graham's gas procurement activities.

Q. Have you reviewed the testimony of Graham Witness John Wallace in regard to the rate design?

A. Yes. I have reviewed his testimony and will discuss his proposed changes to Graham's rate design as part of my testimony.

RATE DESIGN

Q. Please discuss Graham's current rate structures.

A. Graham currently has three customer classes including residential, commercial, and irrigation. Graham's residential customers currently pay a monthly customer charge of $10.50, a margin rate of $0.23444 per therm per therm, as well as the cost of gas component. Irrigation customers currently pay a monthly customer charge of $17.00, a margin rate of $0.09944 per therm, as well as the cost of gas component. Commercial customers currently pay a monthly customer charge of $18.00, a margin rate of $0.24044 per therm, as well as the cost of gas component. Additionally, customers pay a purchased gas adjustor ("PGA") rate that varies with changing natural gas commodity costs.

Q. Please describe what the rate design components are for a natural gas utility like Graham.

A. For a natural gas utility, costs fall into two general categories. The first category is the gas cost component, which captures the cost of the natural gas commodity as well as the cost of interstate pipeline transportation to deliver the natural gas from production areas in New Mexico and Texas to Graham's receipt points on the El Paso Natural Gas interstate pipeline system. An interest component is applied to any over or under-collected PGA bank balance. These costs are passed through the PGA mechanism. The second category captures all costs other than those passed through the PGA mechanism. These costs include things like labor, billing, and infrastructure costs. These costs are recovered through the monthly customer charge as well as the per therm margin rate. In a rate case, the Commission addresses the margin cost components of rates. The Commission may choose to adjust how the PGA mechanism works in a general rate proceeding, but does not generally set the monthly PGA rate, which is set automatically by established mathematical calculations.

Q. Please discuss how Graham represents the cost of gas component in its rate filing.

A. Unfortunately, Graham represents the cost of gas differently in relation to its proposed rates than it does in relation to the current rates, making it unnecessarily difficult for readers to determine the actual changes being proposed for the per therm margin rate. In representing its present rates, Graham reflects a base cost of gas of $0.59056 per therm and a monthly purchased gas adjustor ("PGA") rate of $0.17757 per therm, for a total cost of gas of $0.76813 per therm. In contrast, Graham proposes a new base cost of gas of $0.81775 per therm, and reflects this proposed higher cost of gas when it represents its proposed rates.

When comparing current and proposed rates, it is best to represent rates using a consistent cost of gas component number, as gas costs are passed through the PGA mechanism and changes in margin rates in a general rate case should not impact the pass through of gas costs. Use of different gas cost numbers in different places makes it difficult to understand the changes in margin rates being proposed by Graham. For example, for irrigation customers, when holding the gas cost component constant between current and proposed rates, Graham is proposing to reduce the margin rate by roughly one-third, from $0.09944 per therm to $0.06974 per therm, but this reduction is not clearly identified anywhere due to the inconsistent representation of the gas cost component by Graham.

Q. What rates are being proposed in this case by Graham?

A. Graham is proposing to increase the residential monthly customer charge from $10.50 to $15.00, the irrigation monthly customer charge from $17.00 to $22.50, and the commercial monthly customer charge from $18.00 to $23.50. Graham is proposing to increase the margin rate for residential customers from $0.23444 per therm to $0.32137 per therm. For irrigation customers, Graham is proposing to decrease the margin rate from $0.09944 per therm to $0.06974 per therm. For commercial customers, Graham is proposing to increase the margin rate for commercial customers from $0.24044 per therm to $0.26885 per therm.

Q. Please comment on Graham's proposed rates.

A. Staff believes that Graham's proposed rates increase the customer charges too much and Staff would favor a more measured increase in customer charges. Staff also believes that the large impact of Graham's proposed rates for residential customers should be moderated to the extent possible, as they bear a much heavier burden from the proposed rate increases resulting from Graham's request. Additionally, Staff is sensitive to the concerns Graham has expressed regarding irrigation customers and their potential to fuel-switch, but does not believe that cutting the margin rate for such customers by almost one-third is justified in a case where all other customers are seeing their margin rates increased significantly. Graham's proposed irrigation customer margin rates result in the largest handful of irrigation bills, which represent the vast majority of actual therm consumption in the irrigation class, actually experiencing a rate decrease as a result of Graham's proposed margin rate for this class. In response to Staff data request STF 5.10, attached as Staff Exhibit RGG-2, Graham indicates that it did not intend to decrease the margin for the irrigation class and that the Company believes that the margin rate for irrigation customers should be increased so that it is more in line with other customer classes.

Q. Please discuss Staff's proposed rates in this case.

A. Staff's proposed rates provide revenues sufficient to provide Graham with the revenue requirement of $1,823,358 calculated by Staff Witness Gary McMurry. Staff moderates the monthly customer charge increases proposed by Graham and spreads the burden of the remaining per therm increase more evenly across Graham's rate classes than Graham's proposal does. The revenue generated from Staff's proposed rates is $1,822,839.

Staff recommends that the residential monthly customer charge be set at $13.00 and the residential margin rate be set at $0.345 per therm. Staff recommends that the irrigation monthly customer charge be set at $21.00 and the irrigation margin rate be set at $0.16 per therm. Staff recommends that the commercial monthly customer charge be set at $24.00 and the commercial margin rate be set at $0.341 per therm.

Q. Please describe how Staff deals with the cost of gas in representing overall rates to be paid by Graham's customers under Staff's proposed rates, as well as Staff's customer bill impact estimates.

A. Staff uses the most recently available cost of gas number reflected in Graham's rates and uses this same number to provide a more accurate comparison of Graham's existing and proposed rates and Staff's proposed rates. The cost of gas number Staff uses for bill estimates is $0.78890 per therm, the overall cost of gas in Graham's rates for December 2009, excluding the $0.16 per therm temporary PGA credit in effect in December 2009. This reflects the current base cost of gas of $0.59056 per therm and the December 2009 monthly PGA rate of $0.19834 per therm. Exhibit RGG-4 provides customer bill estimates under Staff's proposed rates as well as Graham's proposed rates and Graham's existing rates.

Q. Please discuss residential customer bill impacts under Staff's proposed rates.

A. For a residential customer bill reflecting mean consumption of 36 therms, the customer bill under Staff's proposal would be $53.82, an increase of 13.7 percent, or $6.48, over the bill of $47.34 under Graham's existing rates.

Q. Please discuss irrigation customer bill impacts under Staff's proposed rates.

A. For mean irrigation customer bill reflecting an consumption of 59 therms, the customer bill under Staff's proposal would be $76.99, an increase of 10.9 percent, or $7.58, over the bill of $69.41 under Graham's existing rates.

Q. Please discuss commercial customer bill impacts would be under Staff's proposed rates.

A. For a commercial customer bill reflecting mean consumption of 289 therms, the customer bill under Staff's proposal would be $357.10, an increase of 11.1 percent, or $35.06, over the bill of $315.48 under Graham's existing rates.

GAS PROCUREMENT REVIEW

Q. Did Staff conduct a review of Graham's gas procurement activities as part of this case?

A. Yes.

Q. Please describe Staff's review of Graham's gas procurement activities.

A. Staff reviewed Graham's procurement activities for gas supplies acquired between January 2006 and June 2009. Attached as Exhibit RGG-3 is the Staff Report on Graham County Utilities, Inc. Natural Gas Procurement Activities.

Q. Please briefly describe Staff's gas procurement review for Graham.

A. Staff's gas procurement review involved reviewing the purchases Graham made for natural gas supplies received between January 2006 and June 2009. Staff issued several sets of data requests and held a number of teleconferences with Graham to discuss various procurement issues. Staff reviewed Graham's purchasing processes, as well as Graham's purchasing of fixed price, monthly index, and daily gas volumes.

Q. Please identify the findings and recommendations contained in Exhibit RGG-3.

A. The Staff Report contains the following findings and recommendations:

1. Graham shall file a document with Docket Control in this proceeding, within 60 days of the Decision in this case, identifying its processes for procuring natural gas supplies, and what person(s) at the Company is(are) responsible for each step of the procurement process.
2. Graham shall actively ensure that the prices it pays BP ("British Petroleum") are competitive and reasonable given market conditions.
3. Graham shall maintain documentation of any price indices used either currently or for past purchases. Such documentation shall include the publication or other source of the index, the index price, any calculations involved in creating the index, and any other pertinent information. As part of its on-going tracking of PGA information, Graham shall ensure that its costs actually paid for gas coincide with the proper indices contained in the relevant purchase agreement(s).
4. Graham shall regularly consider, as part of its gas procurement activities, the possibility of conducting a competitive solicitation.
5. Staff finds that the prices paid by Graham during the period of January 2006 through July 2009 are prudent given natural gas market conditions and Graham's needs and position in the marketplace.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your findings and recommendations.

A. My testimony includes the following findings and recommendations:

Rate Design

1. The residential customer charge should be set at $13.00 per month and the residential margin rate should be set at $0.345 per therm.
2. The irrigation customer charge should be set at $21.00 per month and the irrigation margin rate should be set at $0.16 per therm.
3. The commercial customer charge should be set at $24.00 per month and the commercial margin rate should be set at $0.341 per therm.

Gas Procurement

4. Graham shall file a document with Docket Control in this proceeding, within 60 days of the Decision, identifying its processes for procuring natural gas supplies, and what person(s) at the Company is(are) responsible for each step of the procurement process.
5. Graham shall actively ensure that the prices it pays BP are competitive and reasonable given market conditions.
6. Graham shall maintain documentation of any price indices used either currently or for past purchases. Such documentation shall include the publication or other source of the index, the index price, any calculations involved in creating the index, and any other pertinent information. As part of its on-going tracking of PGA information, Graham shall ensure that its costs actually paid for gas coincide with the proper indices contained in the relevant purchase agreement(s).
7. Graham shall regularly consider, as part of its gas procurement activities, the possibility of conducting a competitive solicitation.

8. Staff finds that the prices paid by Graham during the period of January 2006 through July 2009 are prudent given natural gas market conditions and Graham's needs and position in the marketplace.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)
M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Executive Consultant III (November 2007 – present), Public Utility Analyst V (October 2001 – November 2007), Senior Economist (August 1997 – October 2001), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, natural gas research and development funding, customer services issues, special contracts, various tariff matters, and other natural gas issues. Conduct economic and policy analyses on a variety of electricity issues in Arizona, power plant and transmission line siting cases, energy efficiency, renewable energy standards, rate design, time-of-use service, and low income issues. Prepare recommendations and present written and oral testimony before the Commission and organize workshops and other proceedings on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission, at the North American Energy Standards Board, and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving as a past Vice-Chair and Chair of the NARUC Staff Subcommittee on Gas.

Testimony

Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.

Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.

Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Resource Planning for Electric Utilities (Docket No. U-000-95-506), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

Black Mountain Gas Company - Northern States Power Company, Merger (Docket Nos. G-03493A-98-0017, G-01970A-98-0017), Arizona Corporation Commission, 1998.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Graham County Utilities Company Rate Case (Docket No. G-02527A-00-0378), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Cave Creek Division Rate Case (Docket No. G-03703A-00-0283), Arizona Corporation Commission, 2000.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. G-01551A-00-0309), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-01-0263), Arizona Corporation Commission, 2001.

Duncan Rural Services – Natural Gas Rate Case (Docket No. G-02528A-01-0561), Arizona Corporation Commission, 2001.

Toltec Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Y-01-0112), September 2001.

Lap Paz Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000AA-01-0116), December 2001.

Bowie Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000BB-01-0118), December 2001.

Southwest Gas Corporation, Acquisition of Black Mountain Gas Company (Docket No. G-01551A-02-0425), Arizona Corporation Commission, 2002.

Wellton-Mohawk Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Z-01-0114), February 2003.

Arizona Public Service Company, Rate Proceeding (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004.

Graham County Utilities Company Rate Case (Docket No. G-02527A-04-0301), Arizona Corporation Commission, 2004.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-04-0876), Arizona Corporation Commission, 2004.

Southern California Edison, Devers – Palo Verde 2 Transmission Line Application before the Arizona Power Plant and Line Siting Committee, (L-00000A-06-0295-00130), 2006.

Semstream Arizona Propane Acquisition of Energy West (Docket G-02696A-06-0515), Arizona Corporation Commission, 2006.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-06-0463), Arizona Corporation Commission, 2007.

Semstream Arizona Propane Acquisition of Black Mountain Gas Company – Page Division (Docket G-03703A-06-0694), Arizona Corporation Commission, 2007.

Northern Arizona Energy, LLC, Northern Arizona Energy Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000FF-07-0134-00133), 2007.

Arizona Public Service, Palo Verde Hub to North Gila 500 kV Transmission Lint Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000D-07-0566-00135), 2007.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-07-0504), Arizona Corporation Commission, 2008.

Arizona Solar One, LLC, Solana Generating Station and Gen-Tie Application before the Arizona Power Plant and Line Siting Committee, (L-00000GG-08-0407-00139 and L-00000GG-08-0408-00140), 2008.

Coolidge Power Corporation, Coolidge Power Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000HH-08-0422-00141), 2008.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-08-0571), Arizona Corporation Commission, 2009.

El Paso Natural Gas Company, Rate Proceeding (Docket No. RP08-426), Federal Energy Regulatory Commission, 2009.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Staff Report on the Rolling Average PGA Mechanism, (Docket No. G-00000C-98-0568),Arizona Corporation Commission, September 6, 2000.

Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. G-01551A-04-0192), Arizona Corporation Commission, June 2, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. E-01345A-05-0895), Arizona Corporation Commission, March 2, 2006.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-01551A-06-0107), Arizona Corporation Commission, May 16, 2006.

Staff Report on UNS Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-04204A-06-0627), Arizona Corporation Commission, January 30, 2007.

Staff Report on Semstream Arizona Propane, Payson Division issues, Arizona Corporation Commission, June 6, 2008.

Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference
1999 – 2007	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2008	NARUC Winter Committee Meetings
2004-2007	NARUC Annual Convention

Memberships

NARUC – Staff Subcommittee on Gas – member, 1998 - present
NARUC - Staff Subcommittee on Gas – Vice-Chair - 2002 - 2004
NARUC - Staff Subcommittee on Gas – Chair - 2005 - 2007
Michigan State Institute for Public Utilities – NARUC Advisory Committee – 2005-2007
NARUC - North American Energy Standards Board Advisory Council – 2006 - present
NARUC – DOE LNG Partnership – 2003 - present

**GRAHAM COUNTY UTILITIES RESPONSES TO
ARIZONA CORPORATION COMMISSION
STAFF'S FIFTH SET OF DATA REQUESTS TO
GRAHAM COUNTY UTILITIES GAS DIVISION, INC.
DOCKET NO. G-02527A-09-0088
AUGUST 12, 2009**

STF 5.10 If the cost of gas is held constant when comparing the current and proposed Graham rates, is Graham proposing a per therm rate decrease for the margin (non-gas cost) portion of the per therm rate for the irrigation customer class?

RESPONSE: **Graham did not intentionally design the rate margin to decrease for the irrigation customer class. Graham does agree that the rate per therm should be increased for the irrigation class so that the margin is more in line with the other classes.**

STF 5.11 Graham cites irrigation customers being very price sensitive. Please provide any studies, communications, or other information Graham has which documents the price sensitivity of irrigation customers.

RESPONSE: **Graham does not have any documentation of the price sensitivity of the irrigation customers. Graham only has personal experience with local farmers and irrigators that have told GCU that they would either quit farming or switch to electric if their natural gas rates were to increased too much. Years ago many irrigation customers did in fact switch from gas to electric due to rising natural gas prices. Since the revenue from natural gas received from the irrigation class is only 0.15% of the total revenue, it does not seem to warrant such a study to determine the exact price sensitivity. See attached Schedule STF 5.11 which shows that most of the irrigation bills are for no usage.**

Staff Report on Graham County Utilities, Inc. Natural Gas Procurement Activities

December 23, 2009

Docket No. G-02527A-09-0088

Table of Contents

INTRODUCTION

Graham County Utilities ("Graham" or "Company") is a relatively small natural gas cooperative that provides natural gas service to approximately 5,000 residential, irrigation, and commercial customers in Graham County, including the towns of Pima and Thatcher. In the test year in this rate case, ending September 30, 2008, Graham had sales of 2,933,418 therms of natural gas. Graham receives its natural gas via the El Paso Natural Gas Company ("El Paso") interstate pipeline system through 54 delivery points off of the pipeline. El Paso is the only interstate pipeline system to which Graham has access. Graham receives full requirements service under El Paso's Rate Schedule FT-2, Firm Transportation Service and holds a Transportation Service Agreement ("TSA") with El Paso that was entered into on August 15, 1991 and expires on August 31, 2011. Graham also holds an Operator Point Aggregation Service Agreement, which enables Graham to combine its many delivery points into a single delivery code for purposes of nominating, scheduling, and accounting activities. Under Graham's TSA with El Paso, Graham holds a maximum daily quantity of 4190 therms, with receipt point rights at four locations in the San Juan supply basin in New Mexico.

This procurement review has involved an assessment of Graham's gas procurement efforts from January 2006 through June 2009. During this time period, Graham spent $8,189,554 purchasing natural gas and interstate pipeline transportation service. Of this amount, approximately $7.5 million was spent on the natural gas commodity, and close to $0.7 million on interstate pipeline service. Graham's historic purchases during this period were reviewed for prudency by comparing the prices paid with natural gas market prices at the time, taking into consideration market conditions. Staff also inquired regarding the processes used by Graham to procure its natural gas supplies. Staff issued a series of data requests to Graham and held a number of telephone conversations with representatives of Graham regarding its procurement activities during the review period. Graham has had a few general rate cases before the Commission since the mid 1990s, but this is the first case during that time period where a procurement review has been conducted. It is not clear when the last procurement review took place for Graham.

GRAHAM PROCUREMENT PROCESSES

Graham does not have a formal procurement plan or other document identifying the processes it uses to purchase natural gas supplies for its customers. However, Graham has indicated that it has unwritten processes and strategies it does follow.

Typically the General Manager discusses natural gas prices at Graham's monthly Board of Directors meeting. The Board authorizes the General Manager to contract for certain volumes and prices. The General Manager then contracts for natural gas supplies after consulting with other Graham personnel, as well as Graham's supplier, BP ("British Petroleum"). While the Board of Directors has ultimate authority at Graham for natural gas procurement activities, the General Manager conducts the actual gas procurement activities, including securing bids, evaluating offers, and authorizing entering into a natural gas purchase contract.

The Commission has issued several decisions in the last decade that have provided direction to Graham regarding its gas procurement activities. In Decision No. 61225 (October 30, 1998), when the Commission implemented the banded 12-month rolling average purchased gas adjustor ("PGA") mechanism for Arizona gas utilities, including Graham, the Commission identified price stability as one of the goals for gas procurement efforts, including those of Graham. Specifically, the order states that:

> "The LDCs should pursue longer term, fixed price supply options as a viable option when they choose which gas supplies to include in their supply portfolios."

and

> "The Commission recognizes price stability as one of the goals of the natural gas procurement process."

This order and the accompanying Staff Report also recognized that supply diversity is a valuable tool in diversifying risk in the gas procurement process.

Further, in Decision No. 68298 (November 14, 2005), the Commission dealt with an application for a very large PGA surcharge from Graham, in the face of a major spike in natural gas prices, largely as a result of Hurricanes Rita and Katrina. At the time Graham was not purchasing any of its supplies under longer term, fixed price contracts, resulting in Graham's customers being very exposed to natural gas market price fluctuations. In that Decision, the Commission ordered that:

> "Graham provide Docket Control, as a compliance item n this docket, a plan by June 30, 2006, and by June 30th each year thereafter, indicating any fixed price supplies the Company has acquired for the following winter heating season and how the Company plans to hedge its natural gas supplies prior to the following winter heating season."

Graham has filed such plans annually each summer, discussing its efforts to secure fixed price supplies.

For a number of years Graham has purchased its natural gas supplies from BP and Wasatch Energy (which was acquired by BP). Graham has indicated to Staff that the Company has a good working relationship with BP and is in regular contact with them regarding Graham's natural gas supply needs. Graham indicated that it is not actively seeking other natural gas suppliers, as it believes that BP provides competitive pricing and that the on-going relationship with BP is beneficial. In response to a data request, Graham indicated the Company has considered using a competitive solicitation process, and that it also attempted to get a competitive bid from another supplier, but the alternative supplier did not respond in a timely fashion. On August 1, 2008, Graham and BP entered into a North American Energy Standards Board ("NAESB") base contract that contained various conditions that would apply to future purchases by Graham from BP. On July 11, 2008, Graham entered into a Transaction

Transaction Confirmation agreement with BP, setting forth basic terms for purchases of monthly index gas and daily (also know as swing) gas.

Graham's unwritten strategy is to contract for approximately 50 percent of its natural gas supplies under fixed price contracts, with a variance of up to 20 percent higher or lower as the Company deems best. These fixed price contracts have typically been either one year in duration or for a shorter number of months covering the winter heating season. For volumes beyond the fixed contract volumes, Graham contracts for a given additional volume, to be priced at the beginning of month Inside FERC El Paso – San Juan index, plus three cents.

For small additional volumes in certain months, Graham pays an average for the month of the daily spot market indices for the Inside FERC El Paso – San Juan index. The monthly average is used, as many of Graham's delivery points off the El Paso pipeline system are sufficiently small that the meters are only read on a monthly basis.

Staff believes that Graham's mix of fixed price contracts, monthly index pricing, and daily spot price average pricing for the volumes discussed above is a reasonable approach to purchasing natural gas for the Company's customers.

Regarding Graham's reliance on BP for all natural gas supplies, Staff generally believes that as a general principle, greater diversity in a supply portfolio is beneficial and expects that Graham will consider diversifying the suppliers it uses. However, given Graham's relatively small size, it is more problematic for Graham to diversify its supply portfolio than it is for larger Arizona local distribution companies ("LDCs") like Southwest Gas and UNS Gas. It is difficult to assess whether and to what extent Graham benefits from its on-going relationship with BP, but it is certainly possible that Graham maintaining an on-going relationship with BP would provide Graham with benefits such as access to BP's market expertise. In past proceedings, including the 2005 PGA surcharge docket referenced above, Graham has indicated to Staff that it has had difficulties locating suppliers to buy natural gas from. Because of this, Staff is reticent to force Graham to actively move away from relying on BP for its natural gas supplies. While Staff will not recommend that Graham actively source natural gas supplies from multiple suppliers, Staff believes that Graham will bear an on-going responsibility to ensure that the pricing and service it receives from BP are competitive and beneficial for its customers in comparison to a model where Graham solicited natural gas purchases from both BP and other suppliers.

REVIEW OF JANUARY 2006 THROUGH JUNE 2009 GAS PURCHASES

Graham's purchases from January 2006 through June 2009 involve a total of 1,002,593 decatherms. Of this volume, 591,378 decatherms involved fixed price contracts, 380,701 decatherms involved index price contracts, and 30,514 decatherms involved daily volumes.

FIXED PRICE CONTRACTS

For the gas supplies from January 2006 through June 2009, Graham entered into a total of 11 fixed price contracts, with one contract being for a four month winter period, and the other ten agreements being for a one year period. All 11 agreements contain sculpted monthly volumes, with much larger volumes during the peak demand winter period, and smaller volumes in shoulder and summer months.

Staff reviewed a variety of information in analyzing these contracts. The primary approach was to review information on various market prices and conditions at the time the contract was entered into. This information included general market conditions, San Juan basin spot market prices, New York Mercantile Exchange ("NYMEX") natural gas futures prices, Gas Daily reported price spreads between the Henry Hub and the San Juan and/or Permian supply basins, and the 12-month strip price at the Henry Hub. The table below shows a composite NYMEX price for comparison to each contract, weighted for each month's contract volume and monthly NYMEX futures prices over the term of each contract. This provides a rough comparison point for the price Graham contracted for compared to what a roughly equivalent contract would look like for NYMEX futures. It should be recognized that San Juan prices typically are lower than Henry Hub prices, the basis for NYMEX futures. In the past a very rough rule of thumb has been that Henry Hub prices are a dollar or so higher than San Juan prices, recognizing that natural gas markets change over time and the actual spread could be significantly higher or lower at times.

Contract Confirmation Date	Contract Period	Contract Price ($/MMBtu)	Volume (MMBtu)	NYMEX Weighted Avg. Futures Price	Differential
11-7-2005	12-05 to 3-06	$9.345	44,033	$11.79	-$2.44
5-8-2006	6-06 to 5-07	$8.55	70,919	$10.18	-$1.64
5-18-2006	6-06 to 5-07	$8.03	70,919	$9.75	-$1.72
1-5-2007	2-07 to 1-08	$6.87	86,034	$7.21	-$0.34
6-26-2007	7-07 to 6-08	$7.77	57,444	$8.55	-$0.78
7-11-2008	9-08 to 8-09	$8.94	56,850	$12.84	-$1.86
7-11-2008	9-08 to 8-09	$10.98	56,850	$12.84	-$3.90
8-25-2008	9-08 to 8-09	$7.835	28,425	$8.72	-$0.89
9-2-2008	11-08 to 10-09	$7.40	56,850	$8.68	-$1.28
2-2-2009	11-09 to 10-10	$5.725	142,311	$6.34	-$0.62
2-19-2009	11-09 to 10-10	$5.20	56,922	$5.92	-$0.72

Note: One MMBtu equals 10 therms

In hindsight, some of Graham's fixed price purchases took place at times when natural gas prices were at or near pricing peaks. For example, Graham entered three fixed price contracts in July and August 2008, when natural gas prices were at or near the peak, before precipitously falling in the following months. However, any discussion of fixed price contracts must recognize the hedging function of such contracts and that at times contracts will be entered into that turn out to be higher than later spot market prices. At the time Graham entered those contracts, there was no way to know that prices would fall steeply within a few months, rather than possibly increasing. A bedrock principle of natural gas procurement is that the hedging of prices by fixing prices, as Graham did here, is not done with the goal of lower costs, but rather with the goal of reducing exposure to the sizable volatility that has been present in the natural gas market for many years. Thus, it is inevitable that at times an LDC such as Graham will enter into contracts that will turn out to have higher prices than the spot market prices in the following months. While Graham could have spread such risk out by entering in those three contracts on dates that were further apart, fundamentally there is no reason to deem these purchases imprudent merely because it can now be recognized in hindsight that they would have saved money if they would have entered into contracts at a later date. After reviewing available information, Staff believes that Graham's contract purchases during the review period are reasonable.

MONTHLY INDEX PURCHASES

Regarding monthly index purchases, Graham had some level of such purchases every month from January 2006 to June 2009, except for April 2007. Graham's on-going provision with BP is that Graham pays the first of the month index price for San Juan gas, plus \$0.03 per decatherm for index purchases. Staff compared the price paid by Graham for its index purchase each month, with the Gas Daily El Paso – San Juan first of the month published index, taking into account the \$0.03 per decatherm premium. The two prices match for most months during the review period. The only two months they do not match are in February and March 2009. In February 2009, the price paid by Graham is \$0.03 per decatherm lower than would be expected from Graham's contract provisions. In March 2009, the volume involved is very small, 28 decatherms, and the reported price Graham paid is \$1.99 per decatherm higher than would be expected from Graham's contract provisions. The net effect of these two discrepancies is that Graham paid \$189 less than would be expected from Graham's contract provisions.

Staff is still in discussions with Graham to identify the reason(s) for these discrepancies. Given that the overall cost paid by Graham was not increased by these two relatively small discrepancies, Staff is not greatly concerned by them. However, to reduce the possibility of such discrepancies in the future, Staff recommends that Graham shall maintain documentation of any price indices used either currently or for past purchases. Such documentation shall include the publication or other source of the index, the index price, any calculations involved in creating the index, and any other pertinent information. As part of its on-going tracking of PGA information, Graham shall ensure that its costs actually paid for gas coincide with the proper indices contained in the relevant purchase agreement(s).

DAILY VOLUME PURCHASES

The daily volume purchases account for 3 percent of the total purchases by Graham during the review period and only occur in a handful of months. Although they are referred to as daily purchases, they are assessed on a monthly basis, as many of Graham's meters off the interstate pipeline are read on a monthly basis and thus daily measurements are not possible in many cases. The daily volumes represent unexpected deviations from the volumes planned for by Graham and BP through the fixed contracts and monthly index purchases discussed above. They are priced at the average of the daily San Juan prices throughout the given month. Staff has reviewed the prices paid for the daily volumes in the months they occur and compared them to an average of the Gas Daily El Paso – San Juan daily indices for all days in each given month. The prices paid by Graham correspond closely with the monthly averages calculated by Staff, with Graham's price paid generally $0.03 to $0.04 per therm higher than the monthly averages calculated by Staff. Given that they are unexpected volumes representing variations from the volumes planned by Graham and BP, Staff believes that this small additional premium is reasonable. However, as discussed in relation to the monthly index contracts, an on-going effort by Graham to track how the prices paid under these daily volume purchases would provide greater clarity regarding how the prices are calculated for current and future purchases.

STAFF FINDINGS AND RECOMMENDATIONS

1. Graham shall file a document with Docket Control in this proceeding, within 60 days of the Decision, identifying its processes for procuring natural gas supplies, and what person(s) at the Company is(are) responsible for each step of the procurement process.
2. Graham shall actively ensure that the prices it pays BP are competitive and reasonable given market conditions.
3. Graham shall maintain documentation of any price indices used either currently or for past purchases. Such documentation shall include the publication or other source of the index, the index price, any calculations involved in creating the index, and any other pertinent information. As part of its on-going tracking of PGA information, Graham shall ensure that its costs actually paid for gas coincide with the proper indices contained in the relevant purchase agreement(s).
4. Graham shall regularly consider, as part of its gas procurement activities, the possibility of conducting a competitive solicitation.
5. Staff finds that the prices paid by Graham during the period of January 2006 through July 2009 are prudent given natural gas market conditions and Graham's needs and position in the marketplace.

Customer Bill Estimates

Residential Class Therms	Current Rates	Company Proposed Rates	Staff Proposed Rates	Percent Increase/ Decrease Company Proposed Rates	Percent Increase Staff Proposed Rates	Increase Staff Proposed Rates
5	$15.62	$20.55	$18.67	31.6%	19.5%	$3.05
10	$20.73	$26.10	$24.34	25.9%	17.4%	$3.61
15	$25.85	$31.65	$30.01	22.5%	16.1%	$4.16
20	$30.97	$37.21	$35.68	20.1%	15.2%	$4.71
25	$36.08	$42.76	$41.35	18.5%	14.6%	$5.26
30	$41.20	$48.31	$47.02	17.3%	14.1%	$5.82
36	$47.34	$54.97	$53.82	16.1%	13.7%	$6.48
40	$51.43	$59.41	$58.36	15.5%	13.5%	$6.92
50	$61.67	$70.51	$69.70	14.3%	13.0%	$8.03
75	$87.25	$98.27	$98.04	12.6%	12.4%	$10.79
100	$112.83	$126.03	$126.39	11.7%	12.0%	$13.56
150	$164.00	$181.54	$183.09	10.7%	11.6%	$19.08
200	$215.17	$237.05	$239.78	10.2%	11.4%	$24.61
300	$317.50	$348.08	$353.17	9.6%	11.2%	$35.67
500	$522.17	$570.14	$579.95	9.2%	11.1%	$57.78
1000	$1,033.84	$1,125.27	$1,146.90	8.8%	10.9%	$113.06
Irrigation Class						
10	$25.88	$31.09	$30.49	20.1%	17.8%	$4.61
25	$39.21	$43.97	$44.72	12.1%	14.1%	$5.51
50	$61.42	$65.43	$68.45	6.5%	11.4%	$7.03
59	$69.41	$73.16	$76.99	5.4%	10.9%	$7.57
75	$83.63	$86.90	$92.17	3.9%	10.2%	$8.54
100	$105.83	$108.36	$115.89	2.4%	9.5%	$10.06
200	$194.67	$194.23	$210.78	-0.2%	8.3%	$16.11
300	$283.50	$280.09	$305.67	-1.2%	7.8%	$22.17
400	$372.34	$365.96	$400.56	-1.7%	7.6%	$28.22
500	$461.17	$451.82	$495.45	-2.0%	7.4%	$34.28
750	$683.26	$666.48	$732.68	-2.5%	7.2%	$49.42
Commercial Class						
10	$28.29	$34.08	$35.30	20.4%	24.8%	$7.01
20	$38.59	$44.66	$46.60	15.7%	20.8%	$8.01
50	$69.47	$76.39	$80.50	10.0%	15.9%	$11.03
100	$120.93	$129.28	$136.99	6.9%	13.3%	$16.06
150	$172.40	$182.16	$193.49	5.7%	12.2%	$21.08
200	$223.87	$235.05	$249.98	5.0%	11.7%	$26.11
289	$315.48	$329.19	$350.54	4.3%	11.1%	$35.06
400	$429.74	$446.60	$475.96	3.9%	10.8%	$46.22
500	$532.67	$552.38	$588.95	3.7%	10.6%	$56.28
750	$790.01	$816.81	$871.43	3.4%	10.3%	$81.42
1000	$1,047.34	$1,081.25	$1,153.90	3.2%	10.2%	$106.56
1500	$1,562.01	$1,610.13	$1,718.85	3.1%	10.0%	$156.84
2000	$2,076.68	$2,139.00	$2,283.80	3.0%	10.0%	$207.12
3000	$3,106.02	$3,196.75	$3,413.70	2.9%	9.9%	$307.68

Assumes constant cost of gas of $0.78890 per therm
(reflecting the existing base cost of gas + the monthly PGA rate of $.19834 per therm for December 2009, and excluding the temporary PGA credit of $0.16 per therm in effect in December 2009)

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY UTILITIES, INC. FOR A RATE INCREASE	))))	DOCKET NO. G-02527A-09-0088

DIRECT

TESTIMONY

OF

PREM K. BAHL

ELECTRIC UTILITIES ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 23, 2009

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SCHEDULES

EXECUTIVE SUMMARY
GRAHAM COUNTY UTILITIES INC., GAS DIVISION
DOCKET NO. G-02527A-09-0088

Prem Bahl's testimony discusses Utilities Division Staff's ("Staff") review of Graham County Utilities Inc., Gas Division's ("Graham") Cost of Service Study ("COSS") for the rate case filed with the Arizona Corporation Commission ("Commission"), and presents the results of Staff's analysis.

Based on its review of Graham's COSS, Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Graham performed the COSS consistent with the methodology generally accepted in the industry, and developed the allocation factors appropriately, except two allocation factors, which were modified by Staff.

2. Staff further concludes that, based on the evaluation of the COSS model utilized by Graham and the change Staff made in one allocation factor, the results of COSS are satisfactory.

3. Staff recommends that Graham continue to utilize the current COSS model, including the revised allocation factor for allocating expenditures associated with Distribution Mains in all future rate cases.

4. Staff further recommends that Graham's COSS cost allocations and factors be accepted with Staff's following Allocation Factor revisions, which are reflected in Staff's attached COSS G-Schedules under Exhibit 1:

   F3 ~ Allocation of Distribution Mains, according to 100% demand.
   F3a ~ Allocation of Mains & Services, according to 67% Demand and 33% Weighted Customers

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Prem K. Bahl. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom and in what capacity are you employed?

A. I am employed by the Arizona Corporation Commission ("Commission") as an Electric Utilities Engineer.

Q. Please describe your educational background.

A. I graduated from the South Dakota State University with a Masters degree in Electrical Engineering in May 1972. I received my Professional Engineering ("P.E.") License in the state of Arizona in 1978. My Bachelor of Science degree in Electrical Engineering was from the Agra University, India in 1957.

Q. Please describe your pertinent work experience.

A. I worked at the Arizona Corporation Commission from 1988 to 1998 as a Utilities Consultant, and have been re-employed at the Commission as an Electric Utilities Engineer since June 2002. During this time period of approximately seventeen years, I conducted engineering evaluations of electric utility rural electric cooperative rate cases and financing cases. I inspected the utility power plants including the Palo Verde Nuclear Generating Station, Four Corners and Cholla coal fired power plants. I was involved with the development of retail competition in Arizona and of Desert Star, an Independent System Operator for the southwest region. I was Chairman of the System Reliability Working Group, which evaluated the impact of competition on system reliability and recommended the establishment of the Arizona Independent System Administrator ("AZ ISA") as an interim organization until commercial operation of Desert Star. Since rejoining the Commission, I have reviewed the utilities' load curtailment plans; coordinated with the Commission Consultant to conduct second through fifth Biennial Transmission Assessment ("BTA") 2002 through 2008, in the state of Arizona. I am involved with power plant and line siting Certificate of Environmental Compatibility ("CEC") cases, such as Harquahala, Panda Gila River and Red Hawk and Coolidge plants, and Tucson Electric Company's ("TEP") and Southwest Transmission Cooperative's ("SWTC") 138 kV and 115 kV circuits, respectively, from Tortolita to Northloop and from Saguaro to Tortolita to Northloop.

From July 2001 to June 2002, I had my own consulting engineering firm, named P. K. Bahl & Associates. During this time, I was involved with deregulation of the electric power industry, formation of Regional Transmission Organizations ("RTO"), (especially the planning), congestion management, business practices and market monitoring activities of the RTO West and the MidWest ISO.

From July 1998 to August 2000, I worked as Chief Engineer at the Residential Utility Consumer Office. During this time period, I performed many of the duties I performed at the Commission. I was also involved with the Distributed Generation Work Group that looked at the impact of development of distributed generation in Arizona on system reliability modifications of interconnection standards currently specified by the jurisdictional utilities. I was a member of the AZ ISA Board of Directors from September 1999 until June 2000. I was involved in the deliberations of the Market Interface Committee of the North American Electric Reliability Council. I also published and presented a number of technical papers at national and international conferences regarding transmission issues and distributed generation.

Prior to my employment with the Commission, I had worked as an electrical engineer with electric utilities and consulting firms in the transmission and generation planning areas for approximately thirty two years, including ten years experience at the Punjab State Electricity Board (PSEB) in India from 1960 to 1970. I worked as Executive Engineer at the PSEB from 1968 to 1970 prior to coming to the USA in 1970.

Q. As part of your assigned duties at the Commission, did you perform an analysis of the application that is the subject of this proceeding?

A. Yes, I did.

Q. Is your testimony herein based on that analysis?

A. Yes, it is.

Q. What is the purpose of your prefiled testimony?

A. The purpose of my testimony is to discuss Staff's review of Graham County Utilities, Inc. Gas Division ("Graham") Cost of Service Study ("COSS") for the rate case, and present the results of this review.

II. COST OF SERVICE STUDY - REVIEW PROCESS

Q. What does the COSS signify?

A. There are three steps to take in performing a COSS. They are: 1) functionalization; 2) classification; and 3) allocation. First, the COSS enables us to determine the system's cost of service by classifying the utility's costs (investments and expenses) by function, such as customer-related, demand-related, and commodity-related functions. Second, the study breaks down these costs by customer classes to reflect as closely as possible the cost causation by respective customer classes. Third, the results of the COSS provide a benchmark for the revenues needed from each customer category by appropriately allocating the revenue requirement for each customer class.

Q. Is there a standard COSS model?

A. There is no standard methodology for designing a COSS, but it is generally advisable to follow a range of alternatives to identify which allocations are more reasonable than others. For that reason, the COSS should be used as a general guide only and as one of many considerations in designing rates.

Q. What was the process Staff used in reviewing Graham's COSS?

A. First, I reviewed the model used by Graham in developing various allocation factors in the COSS. Second, I reviewed the Test Year ("FYE 2008") rate base, revenues and expenses in the filed rate case, adjusted by Graham's Pro Forma adjustments, and matched them with the appropriate schedules contained in the application. Third, I incorporated the Construction Work in Progress ("CWIP") adjustment of Staff witness, Gary McMurry, in the COSS.

Q. Did Staff conduct a separate independent COSS?

A. After studying Graham's model, I decided that the best method for review would be to replicate Graham's COSS and make the appropriate Staff revisions and adjustments. The accuracy of the COSS model was established by the fact that all the revisions and adjustments flowed through the relevant G-Schedules. The results of Staff's COSS are attached to this testimony as Schedules G-1 thru G-8 under Exhibit 1.

III. ALLOCATION OF DISTRIBUTION MAINS

Q. What comments does Staff have regarding Graham's allocation of Distribution Mains?

A. This account is the largest single plant account. It constitutes over forty-eight percent (48.18%) of Gross Plant-in-Service, according to Graham's figures used in its COSS. Graham allocated fifty percent (50%) of Mains according to demand, and the other fifty percent (50%) according to the number of weighted customers (weighted according to installation and meter reading costs).

Q. What method did Staff use to allocate Distribution Mains?

A. Staff allocated Distribution Mains according to 100% peak demand.

Q. Why did Staff choose to allocate Distribution Mains according to demand and not split the allocation between demand and number of weighted customers as Graham did?

A. Distribution Mains are designed, by necessity, to meet peak demands. Based on this fact, Mains were allocated using only demand. This allocation method was also used in Graham's last rate case (Docket No. G-02527A-04-0301; Decision No. 67748).

Q. Did Staff make any other change in Graham's allocation factors?

A. Yes, the allocation factor for Distribution Operating Expenses for Mains and Services was changed to sixty-seven percent (67%) according to demand and to thirty-three percent (33%) according to weighted customers, as opposed to Graham's allocation of fifty percent (50%) to each of these two classifications.

Q. Why did Staff make this change?

A. This change gave accurate reflection of the ratio of the Distribution Mains to Services included in the Gross Utility Plant in Service (reference Schedule G-6 under Exhibit 1). Graham is in agreement with this change.

Q. What is the effect of the above-noted two changes?

A. These changes in the two allocation factors resulted in shifting of rate base from residential and irrigation customers to commercial customers. A corresponding shift of operating expenses occurred from residential and irrigation customers to commercial customers. These shifts resulted in an increase in rate of return on rate base for residential and irrigation customers and a decrease in rate of return on rate base for commercial customers.

IV. CONCLUSIONS AND RECOMMENDATIONS

Q. Based upon your testimony, what are Staff's conclusions and recommendations regarding the COS study?

A. Based on its review of Graham's COSS, Staff's conclusions and recommendations are as follows:

1. It is Staff's conclusion that Graham performed the COSS consistent with the methodology generally accepted in the industry, and developed the allocation factors appropriately, except two allocation factors which were modified by Staff.

2. Staff further concludes that, based on the evaluation of the COSS model utilized by Graham, and the changes Staff made in the two allocation factors mentioned above, the results of COSS are satisfactory.

3. Staff recommends that Graham continue to utilize the current COSS model including the revised allocation factors for allocating expenditures associated with Distribution Mains and Operating Expenses for Distribution Mains and Services in all future rate cases.

4. Staff further recommends that Graham's COSS cost allocations and factors be accepted with Staff's following revisions and adjustments, which are reflected in Staff's attached COSS G-Schedules:
   a. Allocation of Distribution Mains according to 100% demand
   b. Staff's operating expense adjustments to Graham's filing to reflect changed Allocation Factor for Operating Expenses for Distribution Mains and Services based on the ratio of sixty seven percent (67%) according to demand and thirty three percent (33%) according to weighted customers.

Q. Does this conclude your testimony?

A. Yes it does.

GRAHAM COUNTY UTILITIES, INC. - GAS
COST OF SERVICE SUMMARY - PRESENT RATES
TEST FISCAL YEAR SEPTEMBER 30, 2008

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	IRRIGATION
Operating Revenues	**3,766,051**	**2,779,836**	**980,695**	**5,520**
Operating Expenses:				
Purchased Gas	2,398,789	1,680,048	714,930	3,811
Distribution Expense - Operations	246,294	194,943	50,660	691
Distribution Expense - Maintenance	278,580	211,166	66,894	520
Customer Account Expense	271,842	254,413	16,941	488
Administrative & General Expense	462,494	386,921	74,694	879
Depreciation	120,068	94,952	24,782	334
Property Taxes	34,375	24,334	10,025	16
Tax Expense - Other	53,893	45,087	8,704	102
Interest Expense -Other	14,126	13,404	704	18
Total Operation Expenses	**3,880,461**	**2,905,268**	**968,334**	**6,859**
Operating Income (Loss)	**(114,410)**	**(125,432)**	**12,361**	**(1,339)**
Rate Base	**2,012,755**	**1,577,120**	**430,469**	**5,166**
% Return - Present Rates	**-5.68%**	**-7.95%**	**2.87%**	**-25.92%**
Return Index	**1.00**	**1.40**	**(0.51)**	**4.56**
Allocated Interest - Long-Term	**134,046**	**105,034**	**28,669**	**344**
Operating TIER - Present Rates	**(0.85)**	**(1.19)**	**0.43**	**(3.89)**

GRAHAM COUNTY UTILITIES, INC. - GAS
COST OF SERVICE SUMMARY - PROPOSED RATES
TEST FISCAL YEAR SEPTEMBER 30, 2008

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	IRRIGATION
Operating Revenues	**4,282,784**	**3,252,683**	**1,024,235**	**5,865**
Operating Expenses:				
Purchased Gas	2,398,789	1,680,048	714,930	3,811
Distribution Expense - Operations	246,294	194,943	50,660	691
Distribution Expense - Maintenance	278,580	211,166	66,894	520
Customer Account Expense	271,842	254,413	16,941	488
Administrative & General Expense	462,494	386,921	74,694	879
Depreciation	120,068	94,952	24,782	334
Property Taxes	34,375	24,334	10,025	16
Tax Expense - Other	53,893	45,087	8,704	102
Interest Expense -Other	14,126	13,404	704	18
Total Operation Expenses	**3,880,461**	**2,905,268**	**968,334**	**6,859**
Operating Income (Loss)	**402,323**	**347,415**	**55,901**	**(994)**
Rate Base	**2,012,755**	**1,577,120**	**430,469**	**5,166**
% Return - Proposed Rates	**19.99%**	**22.03%**	**12.99%**	**-19.23%**
Return Index	**1.00**	**1.10**	**0.65**	**(0.96)**
Allocated Interest - Long-Term	**134,046**	**105,034**	**28,669**	**344**
Operating TIER - Proposed Rates	**3.00**	**3.31**	**1.95**	**(2.89)**

Schedule G-3

Date: December 14, 2009

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2008
UNIT COSTS

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL	IRRIGATION
UNIT COSTS - PRESENT RATES:				
DEMAND				
Amount	565,551	449,577	115,247	727
Bills	60,728	57,621	3,028	79
Therms	2,933,418	2,054,499	874,268	4,651
Per Bill	9.31	7.80	38.06	9.20
Per Therms	0.1928	0.2188	0.1318	0.1563
COMMODITY:				
Amount	2,262,437	1,584,559	674,291	3,587
Per Therms	0.8177	0.8177	0.8177	0.8177
CUSTOMER:				
Amount	938,063	745,700	191,157	1,206
Per Bill	15.45	12.94	63.13	15.26
UNIT COSTS - PROPOSED RATES:	1,503,614			
DEMAND				
Amount	759,909	604,079	154,853	977
Per Bill	73.99	10.48	51.14	12.37
Per Therms	0.6812	0.2940	0.1771	0.2100
COMMODITY:				
Amount	2,262,437	1,584,559	674,291	3,587
Per Therms	0.8177	0.8177	0.8177	0.8177
CUSTOMER:				
Amount	1,260,438	1,001,967	256,850	1,620
Per Bill	122.72	17.39	84.83	20.51
	2,020,347			

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2008
ALLOCATION OF RATE BASE

DESCRIPTION	FACTOR	TOTAL	CONSUMER CLASS RESIDENTIAL	COMMERCIAL	IRRIGATION
GROSS PLANT IN SERVICE:					
Demand	D-1	1,889,784	1,337,766	551,135	883
Commodity	CM-1	-			
Customer - Weighted	C-1	1,967,973	1,691,956	266,738	9,279
Customer - Unweighted	C-2	-			
Total		**3,857,757**	**3,029,722**	**817,873**	**10,162**
ACCUMULATED DEPRECIATION:					
Demand	D-1	925,533	655,179	269,922	432
Commodity	CM-1	-			
Customer - Weighted	C-1	963,826	828,645	130,637	4,544
Customer - Unweighted	C-2	-			
Total		**1,889,359**	**1,483,824**	**400,559**	**4,976**
NET PLANT IN SERVICE		**1,968,398**	**1,545,898**	**417,314**	**5,186**
WORKING CAPITAL:					
Demand	D-1	49,075	34,740	14,312	23
Commodity	CM-1	-	-	-	-
Customer - Weighted	C-1	56,504	48,579	7,659	266
Customer - Unweighted	C-2	6,049	5,739	302	8
Total		**111,628**	**89,058**	**22,273**	**297**
LESS:					
CONSUMER DEPOSITS	C-1	**67,270**	**57,835**	**9,118**	**317**
TOTAL RATE BASE		**2,012,755**	**1,577,120**	**430,469**	**5,166**

RECONCILIATION

TOTAL RATE BASE (from G-6)		2,080,028
CONSUMER DEPOSITS	C-1	**67,270**
		2,012,758

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2008
ALLOCATION OF INCOME STATEMENT

DESCRIPTION	FACTOR	TOTAL	CONSUMER CLASS (PRESENT) RESIDENTIAL	COMMERCIAL	IRRIGATION	TOTAL	CONSUMER CLASS (PROPOSED) RESIDENTIAL	COMMERCIAL	IRRIGATION
REVENUES:									
Gas Sales - Adjusted		3,744,531	2,759,417	979,622	5,492	4,225,020	3,197,875	1,021,355	5,790
Service Charges & Other Revenues	C-2	21,520	20,419	1,073	28	57,764	54,809	2,880	75
Total		**3,766,051**	**2,779,836**	**980,695**	**5,520**	**4,282,784**	**3,252,683**	**1,024,235**	**5,865**
OPERATING EXPENSE:									
Purchased Gas	CM-1	**2,398,789**	**1,680,048**	**714,930**	**3,811**				
Distribution Expense - Operations:									
Demand	D-1	110,682	78,351	32,279	52				
Commodity	CM-1	-							
Customer - Weighted	C-1	135,612	116,592	18,381	639				
Customer - Unweighted	C-2	-							
Total		**246,294**	**194,943**	**50,660**	**691**				
Distribution Expense - Maintenance:									
Demand	D-1	186,649	132,128	54,434	87				
Commodity	CM-1	-							
Customer - Weighted	C-1	91,931	79,038	12,460	433				
Customer - Unweighted	C-2	-							
Total		**278,580**	**211,166**	**66,894**	**520**				
Customer Accounts Expense:									
Demand	D-1	-							
Commodity	CM-1	-							
Customer - Weighted	C-1	-							
Customer - Unweighted	C-2	271,842	254,413	16,941	488				
Total		**271,842**	**254,413**	**16,941**	**488**				
Admin. & General Expense:									
Demand	D-1	170,041	120,371	49,591	79				
Commodity	CM-1	-	-	-	-				
Customer - Weighted	C-1	122,789	105,567	16,643	579				
Customer - Unweighted	C-2	169,664	160,983	8,460	221				
Total		**462,494**	**386,921**	**74,694**	**879**				

Date: December 14, 2009

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2008
ALLOCATION OF INCOME STATEMENT

			CONSUMER CLASS		
DESCRIPTION	**FACTOR**	**TOTAL**	**RESIDENTIAL**	**COMMERCIAL**	**IRRIGATION**
Depreciation:					
Demand	D-1	54,506	38,585	15,896	25
Commodity	CM-1	-			
Customer - Weighted	C-1	65,562	56,367	8,886	309
Customer - Unweighted	C-2	-			
Total		**120,068**	**94,952**	**24,782**	**334**
Property Taxes:					
Demand	D-1	15,605	11,047	4,551	7
Commodity	CM-1	-			
Customer - Weighted	C-1	18,770	13,287	5,474	9
Customer - Unweighted	C-2	-			
Total		**34,375**	**24,334**	**10,025**	**16**
Tax Expense - Other:					
Demand	D-1	19,815	14,027	5,779	9
Commodity	CM-1	-	-	-	-
Customer - Weighted	C-1	14,307	12,301	1,939	67
Customer - Unweighted	C-2	19,771	18,759	986	26
Total		**53,893**	**45,087**	**8,704**	**102**
Interest Expense - Other:					
Demand	D-1	-			
Commodity	CM-1	-			
Customer - Weighted	C-1	-			
Customer - Unweighted	C-2	14,126	13,404	704	18
Total		**14,126**	**13,404**	**704**	**18**
TOTAL OPERATING EXPENSES		**3,880,461**	**2,905,268**	**968,334**	**6,859**
OPERATING INCOME (LOSS)		**(114,410)**	**(125,432)**	**12,361**	**(1,339)**
OPERATING INCOME PERCENT		**-3.04%**	**-4.51%**	**1.26%**	**-24.26%**

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2008
FUNCTION OF RATE BASE COMPONENTS

DESCRIPTION	FACTOR	TOTAL	FUNCTION	SPECIFIC	DEMAND	COMMODITY	CUST. - WT	CUST.
GROSS UTILITY PLANT IN SERVICE								
Distribution Plant:								
Distribution Mains	F-3	1,765,026	1,765,026		1,765,026			
Org. & Land & Land Rights	F-3a	44,016	44,016		29,491		14,525	
Services	F-4	792,695	792,695				792,695	
Meters & Regulators	F-5	1,061,544	1,061,544				1,061,544	
Total Distribution Plant		**3,663,281**	**3,663,281**	-	**1,794,517**	-	**1,868,764**	-
Percent	F10	**100.00%**	**100.00%**	**0.00%**	**48.99%**	**0.00%**	**51.01%**	**0.00%**
General Plant:								
Structures & Improvements	F10	3,309	3,309		1,621		1,688	
Office Equipment	F10	2,750	2,750		1,347		1,403	
Transportation Equipment	F10	-	-		-		-	
Tools & Shop Equipment	F10	124,531	124,531		61,004		63,527	
Power Operated Equipment	F10	63,887	63,887		31,296		32,591	
Total General Plant		**194,477**	**194,477**	-	**95,268**	-	**99,209**	-
Percent	F10	**100.00%**	**100.00%**	**0.00%**	**48.99%**	**0.00%**	**51.01%**	**0.00%**
GROSS PLANT IN SERVICE		**3,857,758**	**3,857,758**	-	**1,889,785**	-	**1,967,973**	-
PERCENT	F10	**100.00%**	**100.00%**	**0.00%**	**48.99%**	**0.00%**	**51.01%**	**0.00%**
ACCUMULATED DEPRECIATION:								
Distribution Plant	F-7	1,768,202	1,768,202	-	866,182	-	902,020	-
General Plant	F-7	121,157	121,157	-	59,351	-	61,806	-
Total Accumulated Depreciation		**1,889,359**	**1,889,359**	-	**925,533**	-	**963,826**	-
WORKING CAPITAL:								
Materials & Supplies Inventory	F-7	91,067	91,067		41,341		49,726	
Prepaids	F-9	20,562	20,562		7,734	-	6,779	6,049
Consumer Deposits		-	-				-	
Total Working Capital		**111,629**	**111,629**	-	**49,075**	-	**56,505**	**6,049**
TOTAL RATE BASE		**2,080,028**	**2,080,028**	-	**1,013,327**	-	**1,060,652**	**6,049**

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2008
FUNCTION OF OPERATING EXPENSES

DESCRIPTION	FACTOR	TOTAL	FUNCTION	DEMAND	COMMODITY	CUST. - WT	CUST.
Purchased Gas	F-2	**2,398,790**	**2,398,790**		**2,398,790**		
Distribution Operating Expenses:							
Supervision & Engineering	F-3a	29,454	29,454	19,734		9,720	
Mains & Services	F-3a	87,772	87,772	58,808		28,964	
Measuring & Reg Stations	F-1	-	-	-			
Customer Installations	F-4	81,098	81,098			81,098	
Other Operating Expenses	F-3a	47,970	47,970	32,140		15,830	
Total Operating Expenses		**246,294**	**246,294**	**110,682**	**-**	**135,612**	**-**
Distribution Maint. Expenses:							
Supervision & Engineering	F-3a	16,964	16,964	11,366		5,598	
Maintenance Expenses	F-3a	261,616	261,616	175,283		86,333	
Total Maint. Expenses		**278,580**	**278,580**	**186,649**	**-**	**91,931**	**-**
Meter Reading Expenses	F-6a	84,109	84,109			39,521	44,588
Customer Accounting & Info. Exp.	F-6	165,917	165,917				165,917
Delinquent Accts. & Uncollectible	F-6	21,816	21,816				21,816
Total Customer Accounts Expenses:		**271,842**	**271,842**	**-**	**-**	**39,521**	**232,321**
Administrative & General Exp.	F-8	462,493	462,493	170,041	-	122,788	169,663
Depreciation	F-7	120,070	120,070	54,507		65,563	
Property Taxes	F-7	34,376	34,376	15,605		18,770	
Taxes - Other	F-8	53,893	53,893	19,814	-	14,308	19,770
Interest Expense - Other	F-6	14,127	14,127				14,127
TOTAL OPERATING EXPENSES		**3,880,465**	**3,880,464**	**557,299**	**2,398,790**	**488,494**	**435,881**
FUNCT. OF SALARIES & WAGES							
Operating Expenses	F-3a	113,485	113,485	76,035		37,450	
Maintenance Expenses	F-3a	122,600	122,600	82,142		40,458	
Meter Reading & Installation	F-6a	77,283	77,283			36,314	40,969
Customer Accounting	F-6	116,856	116,856				116,856
Total		**430,223**	**430,223**	**158,177**		**114,221**	**157,825**
Percent	F-8	**100.00%**	**100.00%**	**36.77%**		**26.55%**	**36.68%**
FUNCTION OF O&M LESS Purchased Gas		1,481,675	1,481,674	557,299		488,494	435,881
Percent	F-9	**100.00%**	**100.00%**	**37.61%**		**32.97%**	**29.42%**
Percent		**100.00%**		**37.61%**		**32.97%**	**29.42%**
	F-6a					46.99%	53.01%

GRAHAM COUNTY UTILITIES, INC. - GAS
TEST FISCAL YEAR SEPTEMBER 30, 2008
ALLOCATION FACTORS

FUNCTION FACTOR	DESCRIPTION	TOTAL	DEMAND	COMMODITY	WEIGHTED CUSTOMER	CUSTOMER
F-1	Demand	100.00%	100.00%			
F-2	Commodity	100.00%		100.00%		
F-3	Distribution Mains	100.00%	100.00%			
F-3a	Mains & Services	100.00%	67.00%		33.00%	
F-4	Services	100.00%			100.00%	
F-5	Meters & regulators	100.00%			100.00%	
F-6	Customer Accounts	100.00%				100.00%
DERIVED FUNCTION FACTOR	**DESCRIPTION**					
F-7	Gross Plant in Service	100.00%	45.40%		54.60%	
F-8	Salaries & Wages	100.00%	36.77%	0.00%	26.55%	36.68%
F-9	O & M Less Purchased gas	100.00%	37.61%	0.00%	32.97%	29.42%

CLASS ALLOCATION FACTORS	DESCRIPTION	TOTAL	CUSTOMER CLASS RESID.	COMM.	IRRIG.
D-1	Winter Peak Demand	100.000%	70.789%	29.164%	0.047%
CM-1	Commodity	100.000%	70.037%	29.804%	0.159%
C-1	Customer - Weighted	100.000%	85.975%	13.554%	0.471%
C-2	Customer - Unweighted	100.000%	94.884%	4.986%	0.130%